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Energy Alberta 1990

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Energy Resources Conservation Board
Review of Alberta Energy Resources in 1990

ERCB

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Energy Alberta

Energy Alberta is published annually by the Energy Resources Conservation Board. The ERCB is an independent body which, in the words of its mission statement, "ensures the orderly, efficient, economic, safe and environmentally sound development of the energy resources of Alberta.

"In carrying out this mission, the ERCB must administer its statutes in a manner that is just and fair, and responsive to the needs and concerns of the Government and the people of Alberta, and of the energy industry."

Each year, ***Energy Alberta*** provides a broad overview of energy developments within the province, seeking to place them in the context of Canadian and global trends. In addition, this publication explains major ERCB regulatory initiatives during 1990. Since these often involve work of a technical nature, this year's text also focuses on the significance of four such matters, namely, reservoir blowdown (page 18), pipeline standards (page 27), sour gas emergency response (page 39) and the ERCB's Core Research Centre (page 43).

This year's edition also features a special section entitled "Energy Decision-making and the Public". It addresses the Board's understanding of the role of the **public**—landowners, residents, special interest groups and communities—in the process of planning new or expanded energy facilities.

As always, we welcome and encourage reader input. Please contact: Editor, ***Energy Alberta***, 10th Floor, 640 - 5 Avenue S.W., Calgary, Alberta, T2P 3G4, or telephone 403-297-3596.

Oil

Gas

Oil Sands

Coal

Electricity

The colour bars above relate to specific energy resources. These same colours are used in charts throughout the publication.

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Access to information means better decisions by all involved in resource development. The ERCB's Core Research Centre has the world's most comprehensive inventory of core and drill cuttings.

Metric/Imperial Energy Equivalents

Energy	1 petajoule	=	energy equivalent of 164 000 barrels of crude oil
		=	energy equivalent of 1 billion cubic feet of natural gas
Oil	1 cubic metre	=	6.3 barrels
Natural Gas	1 cubic metre	=	35.3 cubic feet
Coal	1 tonne	=	0.98 long ton (2240 pounds)
		=	1.1 short ton

Important Events of 1990

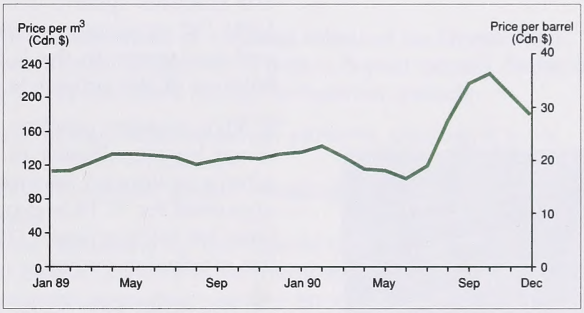
Crude oil prices were generally weak during the first half of 1990 as total production by members of the Organization of Petroleum Exporting Countries (OPEC) exceeded established quotas, creating a surplus on international markets. The price of benchmark West Texas Intermediate crude oil (WTI) fell to $15.30 (U.S.) per barrel in June, then jumped sharply following Iraq's invasion of Kuwait in August. The loss of more than 4 million barrels of oil per day from Iraq and Kuwait, along with related political factors, pushed the WTI price to a high of $40.42 (U.S.) in October. Despite reduced production from Iraq and Kuwait, there continued to be an oversupply of oil on world markets as other OPEC members expanded oil output. The ERCB expects generally soft oil prices over the next 4 years.

There has been a surplus of natural gas in North America for almost a decade. Prices remained weak throughout 1990, the result of a lack of demand and strong competition among gas producers.

The plant gate price for natural gas ranged between $1.50 and $1.60 (Cdn) per gigajoule throughout 1990, about the same as 1989 levels. Propane and butane prices recovered from depressed levels in 1989. The worldwide marketing of coal continues to be extremely competitive, reflected in a year of poor revenues for Alberta's coal industry, especially export-oriented operations.

1. Alberta Weighted Average Field Price Light Oil

Events in the Persian Gulf brought an end to weak oil prices in August as purchasers scrambled to secure supply after Iraq's occupation of Kuwait.

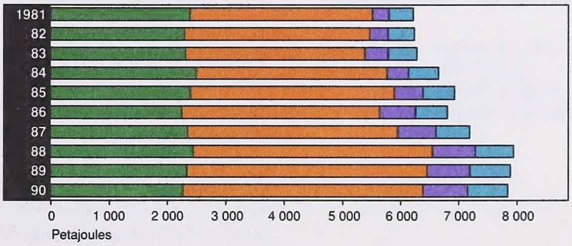


2. Alberta Hydrocarbon Energy Resources

10-year production

Natural gas production continues to dominate Alberta's total energy picture as conventional oil production gradually wanes.

🟩 Oil
🟧 Gas
🟪 Oil Sands
🟦 Coal



Shell Canada Gets Green Light for Caroline Development

On the supply side, the ERCB approved Shell Canada Limited's $825-million proposal to develop the Caroline Beaverhill Lake sour gas reservoir discovered in 1986. The processing plant is expected to produce as much as 2.63 million cubic metres per day of sales gas, and add considerably to Alberta's production of sulphur and natural gas liquids.

The project, consisting of a network of wells and gathering facilities, a large gas processing plant, a sulphur handling installation and a liquid sulphur pipeline, is scheduled to come on stream by the end of 1992. Shell expects to employ 1620 people during the peak construction period and generate 180 permanent jobs. (For more details on this project, see pages 15 and 26.)

Shift to Continental Gas Market

Late in 1990, the National Energy Board (NEB) and the U.S. Federal Energy Regulatory Commission approved the first phase of the Iroquois Transmission System pipeline. TransCanada PipeLines (TCPL) spearheaded this $546-million joint venture to build a 580-kilometre pipeline from Iroquois, Ontario, to Long Island, New York. The line will be able to carry 16 million cubic metres per day of Canadian gas. Construction is scheduled to begin in March 1991, with start-up in January 1992.

The Iroquois system was only one part of TCPL's application for a $2.6-billion 1991/92 expansion to increase natural gas deliveries to Canadian markets and customers in the U.S. northeastern states. An NEB decision on the balance of the project is expected early in 1991.

1990 witnessed approvals for several major pipelines carrying Alberta gas to North American markets.

TCPL's massive pipeline expansion raised a major concern within industry about how to allocate expansion costs among existing and potential shippers. After a prolonged hearing, the NEB announced in November that all facilities approved for TCPL's expansion for 1991/92 will be rolled into the existing rate base for toll purposes. That is, all of TCPL's shippers will share in the cost of the expansion project.

On the other side of the continent, the California Public Utilities Commission (CPUC) questioned the limited opportunity for "non-core" customers in California to contract for short-term gas supplies from Alberta. Intense negotiations among industry and government leaders in both countries led to a compromise requiring the Pacific Gas and Electric Company (PG&E) to make available 7 million cubic metres per day of firm capacity on its interstate pipeline (Pacific Gas Transmission) to the state's non-core customers. The agreement allows these buyers to negotiate firm gas supply directly with Alberta gas producers for the first time.

The growth of natural gas exports prompted NOVA Corporation of Alberta (NOVA) to continue to expand the province's gas-gathering network. During 1990, NOVA invested $700 million as part of an estimated $2-billion phased expansion by 1992. (For more on NOVA's expansion, see page 25.)

Alberta's Role in Achieving Environmental Objectives

Alberta's natural gas producers could benefit from stricter U.S. power plant emission standards in future.

On a global, continental and national scale, 1990 witnessed a number of environmental initiatives that could have profound effects on Alberta.

U.S. Announces Tough New Clean Air Act

The United States government tightened its Clean Air Act in November 1990, with a sweeping initiative that will require American electric power plants to cut acid-forming sulphur emissions in half by the turn of the century. New sulphur emission standards imposed on mid-western coal and oil-fired power plants should promote the substitution of natural gas and possibly low-sulphur coal, creating new market opportunities for Alberta.

In addition, the U.S. government will bring in reductions in allowable emissions of hydrocarbons and nitrogen oxides from new passenger cars. Stricter vehicle exhaust emission standards likely will stimulate the conversion and substitution of methanol and natural gas for unleaded gasoline. This development also will tend to promote the use of propane and "reformulated" gasoline and create demand for methyl tertiary butyl ether (MTBE) and other environmentally benign octane enhancers. Work is already under way on a new MTBE plant east of Edmonton (see page 16).

Canadian Green Plan to Affect Alberta's Energy Industry

In late December 1990, the Government of Canada released its Green Plan, allocating $3 billion to environmental objectives over a 5-year period. Some of the provisions which may affect Alberta's energy industries include

- development of a system of tradeable emission permits, making it more attractive for industry to reduce emissions,
- an outlay of $575 million to combat global warming caused by the combustion of fossil fuels,
- a cap on sulphur dioxide emissions by the turn of the century, with British Columbia, Alberta and Saskatchewan to be included for the first time,
- negotiations with automobile manufacturers to improve fuel efficiency, and
- accelerated development of alternative fuels and sources of energy.

Clean Air Strategy for Alberta

Around the world, governments have recognized that the most effective way to reduce global emissions is to improve energy efficiency at the point of end-use. During 1990, Alberta Environment and Alberta Energy launched an ambitious public consultation program which asked Albertans

- to help identify and clarify the most important issues associated with energy production and use in this province that need to be addressed in developing a clean air strategy, and
- to outline practical and achievable actions to reduce emissions aimed at both consumers and producers of energy.

The results will be incorporated in the province's Clean Air Strategy.

Energy Decision-making and the Public

In June 1989, the ERCB and Alberta Environment released an informational letter entitled "Public Involvement in the Development of Energy Resources".

It was an important milestone. It confirmed for industry the expectation that companies should carry out effective community consultation programs throughout the lifetimes of their energy projects, and also spelled out the broad responsibilities of relevant government departments and agencies.

The guide also provided suggestions on how the public could make the energy development process more workable, more productive and less confrontational. In this section of ***Energy Alberta****, we will examine this issue.*

Involvement Trend Began 20 Years Ago

The ERCB's strong support of public involvement is based on its long-standing commitment to fairness. Provincial legislation requires the Board to give people directly affected by a resource development an opportunity to be heard.

In the early 1970s, the ERCB first began to see a trend. Locally-affected residents were expecting more involvement in energy development. They wanted more of a say in how energy facilities would affect them. This trend would continue to grow.

Industry, regulators and the public entered this new era with few ground rules about how to deal with the variety of public interests. But, over the years, the ERCB has attempted to accommodate new directions in several ways. We modified our application review process to encourage mediation of disputes. Above all, we promoted early contact between the company and people who would be affected by energy projects. At first glance, this changed process may not seem as efficient as before, but the Board is convinced it has produced a fairer and more productive regulatory system for the long run.

The Public's Role: Five Case Studies

Perhaps the best way to illustrate how landowners, groups and communities can participate in the energy decision-making process is to introduce five individuals from a hypothetical community facing a major energy development. While these are not "real" people, their stories are drawn from the hundreds encountered by the ERCB over the years.

In this imaginary scenario, a company announces plans to look for a site to construct a sizeable energy facility. The preferred choice is near a rural community. What follows are the mixed reactions expressed by local people.

Jim is Pro-development

Jim's grandfather settled this area at the turn of the century. Over the generations, his family expanded their cattle ranch, and now runs a large feed-mixing operation, too. Jim is also part owner of the town's hardware store.

Jim has served on town council for many years and is outspoken about the need to attract new business to increase the tax base. It is well known that Jim feels the energy industry has had a good track record for building safe, clean facilities, and for supporting community projects.

Vera Lives Close to the Proposed Energy Facility

With the proposed site only 1 kilometre from her home, Vera has some very real concerns about her family's health and safety. She is also worried about threats to the environment, and possible consequences for the value of her property. She is bewildered by how fast everything seems to be happening and uncertain how she can have input into the plans of a big company. Instinctively, she starts to discuss things with her neighbours.

Barbara Wants to Preserve the Community

For Barbara, this latest development proposal is just one more threat to a community she adopted as her own just a decade ago. After many years in the city, she took advantage of an opportunity to set up her own business in this small town. She was surprised at how much she had come to value the slower pace, friendly people and the ability to make a difference.

Above all, Barbara fears this type of industrial development will bring irrevocable—and negative—change to her community. The more reading and talking she does, especially with her contacts around the province, the more convinced Barbara is that the community doesn't need such development, at least not right now. She is becoming more at ease with the label "activist".

If the Process Is Fair, Pat Could Live with the Results

Pat couldn't make up her mind about the proposed development. Normally, she wasn't the kind of person to get involved. After reading newspaper articles about the project, she began to wonder. Would it be safe? When she attended a public meeting she wasn't sure that the company was making an honest effort to listen to what people were saying.

She felt she could still go either way. If the company kept its promise about making the site selection process open and fair—with clear explanations about the technical side of things—and asked some respected people to work on a community advisory group, she would feel a lot better about this development.

"I Can't Do Anything About It Anyway"

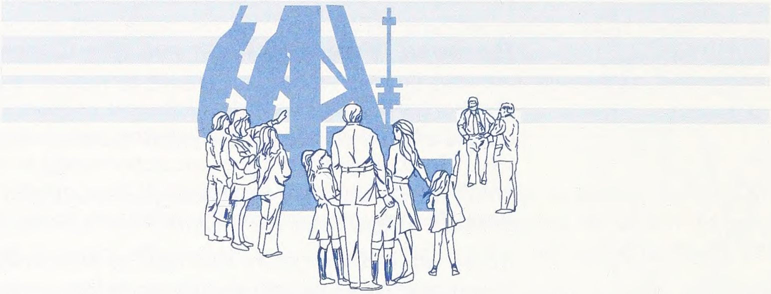
Although Hal read the newspapers and heard talk about the new facility, he didn't pay much attention. He had more pressing things to worry about just to keep his head above water and the farm afloat in troubled times. Anyway, he figured oil people always got their own way eventually, and opposing them was just a waste of time.

Now, how can these typical Albertans best integrate themselves into the energy decision-making process?

Learning Applies to Everyone

Although all of the five individuals have different perspectives, they share the common need to learn and understand more about the proposed project. Probably the most important thing any Albertan can do is to take every opportunity to learn more about the business of energy resource development—both the advantages and disadvantages. The scope of the subject matter may be extensive, but it's important for citizens who live in a resource-based province to understand an industry that affects their lives.

For the project described above, regulatory agencies encourage people to come to as full an understanding of the specifics of the proposed development as they possibly can. That may mean asking the company to set up a visit to a similar site elsewhere, or getting the most up-to-date information on relevant risk and health studies.



The ERCB Needs to Hear Both Sides—Supporters and Opponents

Let's first look at Jim, the community booster. Often, the ERCB has found that those residents who are basically in favour of careful, safe energy developments may not be heard from during the consultative or hearing processes. They may believe, for example, that the company represents their views and therefore may choose not to make an official presentation.

But the Board, the company and the community need to hear all points of view represented in a directly affected community, including those of people like Jim. As an elected official, Jim also has a wider set of obligations to represent his constituents. Even though he may openly support the project, he has a duty to be aware of the people who oppose development, and why. He is perhaps one of the best people to advise "outsiders"—that is, government departments, regulators and developers—about how people in his community view the project and the best way to address concerns.

Directly Affected Residents Can Make a Real Difference

As a directly affected resident, it's very important for Vera to bring her concerns to the company or to the ERCB as soon as possible. When she first heard about the proposed development—through the community grapevine—she should have been in touch with the company, even if her concerns weren't entirely clear in her mind yet.

Because she lives close to the proposed site, Vera is protected by some very important legislation that could assist her in ensuring her concerns are considered during the planning process. For example, by law, a company must notify anyone living within a certain distance of a proposed energy development. In Vera's case, she might be contacted directly by someone from the company or by a notice in the mail, or she may see a formal notice about the application in the newspaper.

If Vera has a concern, it's up to her to respond within a reasonable period of time. The ERCB tries to be fair to all interested parties in setting a date when submissions will be required. Because of her proximity to the proposed site, there is also a funding mechanism in place to assist with this work, including advice from legal counsel and a variety of technical experts.

Another positive step—one that Vera has already taken—is to contact her neighbours, to see if they share her concerns. A group of landowners with a common cause often present a more forceful case and thus find their issues are more readily addressed by the applicant. In the ERCB's experience, local people are quite capable of speaking for themselves. They just need to know they are welcome and they need to understand when their comments and concerns should be brought forward to achieve maximum benefit for all.

Support Is Available

Now let's meet Barbara. She represents those people who tend to oppose projects that may change the community or affect the environment. As her story indicates, she and others in her group may already be well on their way to learning as much as they can about the specifics of this development and the experiences of other communities in similar situations.

The problem, as Barbara would be quick to point out, is that inexperienced local residents frequently lack the resources to tackle such issues. Time, money, legal advice and experts seem to be out of reach. But support is available. Although people like Barbara often must volunteer their time to become involved, there usually is funding available for research, and advice in preparing their case, through the company or the ERCB.

For large resource facilities, a public hearing may still be required. That does not mean that the community consultation/negotiation process is a waste of time. On the contrary, Barbara's group could be of assistance to help narrow the issues for the hearing.

Public hearings, in the ERCB's experience, work best when people directly concerned with and affected by a specific application attempt to resolve as many issues as possible prior to a formal hearing. It's best to bring only unresolved issues that fall within the ERCB's jurisdiction to the actual hearing. For this to occur, the public consultation/negotiation process should deal with the wider societal issues underlying proposals for major resource development.

The Middle-of-the-roader Could Go Either Way

Pat is a "middle-of-the-roader" and could go either way on this particular project. Studies indicate that up to 50 per cent of residents in any community fall into this category. What matters most to them is that they have the opportunity to understand all the implications of the project, and how open and fair the process of decision-making is.

As part of the general public, Pat has a view that company representatives and regulators may need to hear. This may mean Pat should consider attending several meetings as the project's parameters change and develop. If she becomes convinced that the company is not really addressing people's concerns, she should bring those to the attention of the company and the ERCB. On the other hand, if Pat becomes more at ease with the development proposal, she should also speak up and explain why she feels this way. It may help others to understand how she arrived at this conclusion.

What About People Who Feel They Can't Participate?

In a free society, the system cannot force people—people like Hal—to take an interest in something, learn about an issue or express their views. Of course, the process does provide the opportunity for everyone to attend public information meetings and to receive information about the project. Hal may be wise to take advantage of these to make sure his questions are answered.

Involvement Is Crucial

The thrust of public consultation is the development of a framework of involvement by all stakeholders. It seems only logical that when a community has to live with the consequences of development, its members will be more comfortable with decisions which reflect their collective interests.

The crucial factor, then, is involvement. Even if the information is complex and difficult to evaluate, people should take an interest in the problems of energy development. Final judgements in such matters require balancing "quality of life" concerns about which people may hold widely differing views. The public should involve itself as a major and very legitimate source of information about these values and choices.

. . .

Several publications served as the basis for this essay:

- *Public Involvement in the Development of Energy Resources*, ERCB Informational Letter IL 89-4.
- "The Rights of Participants in the Review of Major Projects", a speech by ERCB Chairman G. DeSorcy given in 1990.
- *Public Consultation Guidelines for the Canadian Petroleum Industry*, a 96-page manual that suggests ways for working successfully with the public, published by the Canadian Petroleum Association in 1989.
- *Fair Play*, a handbook produced in September 1990 by the residents of Eagle Valley, Alberta.

For information on how to obtain these publications, please contact the ERCB Communications Department, 640-5 Avenue SW, Calgary, Alberta, T2P 3G4, Telephone 297-4601.

Alberta's Energy Resources

This section of ***Energy Alberta*** reviews the major events of 1990 as they apply to each of the province's major resource sectors: oil, oil sands, natural gas, coal, electricity and pipelines.

3. Alberta's Energy Resources (in petajoules)

Remaining Reserves at the End of 1990

Conventional Oil and Equivalent	20 000
Natural Gas and Equivalent	63 500
Bitumen and Synthetic Crude Oil	153 000
Coal	575 000

1990 Marketable Production

Conventional Oil and Equivalent	2 275
Natural Gas and Equivalent	3 320
Bitumen and Synthetic Crude Oil	765
Coal	670
Hydro	6

1990 Sales

	To Alberta	To Other Provinces	Exports	**Total**
Crude Oil and Equivalent	740	1 130	1 170	3 040
Gas	695	1 165	1 460	3 320
Coal	480	40	150	670
Hydro	6	0	0	6
Total	**1 921**	**2 335**	**2 780**	**7 036**
Per cent of Sales	27	33	40	100

Conventional Crude Oil

Alberta's conventional light-medium crude oil production in 1990 was an estimated 42.7 million cubic metres, about 6 per cent less than in 1989. Light-medium crude oil productivity has steadily decreased during the past 2 years, mainly because production from the province's large, mature oil pools has continued to decline. Meanwhile, drilling activity has not provided replacement capacity.

In contrast, 1990 production of conventional heavy crude oil was an estimated 9.7 million cubic metres, 5 per cent more than in the previous year. Daily production of this resource has been increasing over the past 2 years, from 23 000 cubic metres per day in 1988 to 28 000 cubic metres per day by the end of 1990.

Although productivity from existing heavy oil wells continued to decline, production from new wells of this type overcame this trend. Heavy crude reservoirs tend to be shallower than the light-medium reservoirs, and thus less costly to drill. For example, the Provost Field in east-central Alberta has seen a total of 710 successful heavy oil wells drilled since 1988. This one field represented 40 per cent of all oil well drilling in the province's conventional heavy oil areas for that period. As a result of this activity, established heavy crude oil reserves have climbed by almost 10 million cubic metres per year between 1988 and 1990.

Heavy crude oil production increased in 1990, in contrast to a decline in light oil production.

Regulatory Review for Horizontal Wells

Horizontal well drilling activity continued to be an attractive venture in 1990. Alberta's energy industry drilled 34 horizontal wells in 1990, up from 27 the previous year. Although horizontal drilling—on an individual well basis—is more expensive than using conventional drilling techniques, the prospect of increased oil production, additional hydrocarbon recovery, reduced surface disturbances and fewer land-use conflicts make this approach attractive. Indeed, in many situations, it may be more cost-effective to use horizontal wells instead of conventional vertical wells.

During 1990, ERCB staff reviewed the general requirements of drilling spacing units and production rate limitations for horizontal wells. Although these wells are presently subject to the same regulations as conventional vertical wells, the ERCB is anticipating some changes in existing requirements where it appears appropriate.

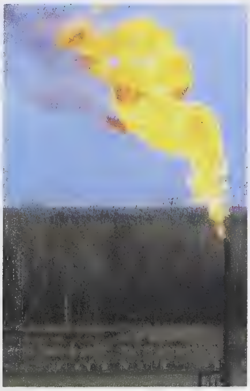
Onus for Well Testing Shifts to Industry

Well testing information is vital to the prudent management of an oil or gas reservoir. However, recent statistics showed that operators spent up to a quarter of a billion dollars annually to run pressure and deliverability tests for Alberta's oil and gas wells. Industry and regulator were concerned that this cost could continue to increase while maturing reservoirs and deregulation were reducing the need for certain test data.

As a result, the ERCB worked with industry to revise pressure testing regulations. A new guide (ERCB Guide G-40) was released in draft form in April 1990 to permit industry to implement new procedures as soon as possible and benefit from cost-saving measures without delay.

In establishing this new regulatory environment for pressure testing, the operator gains more flexibility, but assumes greater responsibility for complying with new standards of test quality and quantity. The ERCB, in turn, will concentrate its resources on providing advice, conducting spot checks, providing feedback to operators and evaluating test results during the next year. The success of the process will be measured by how well data needs are being served, the quality of data filed with the ERCB and reductions in testing and administrative costs. If no problems arise, the guide will be adopted as part of ERCB regulations.

Solution Gas Recovery



Solution gas is a major source of the flaring at oil wells in Alberta.

Crude oil under pressure in a reservoir contains a certain amount of natural gas dissolved in the oil. This gas, known as solution gas, is produced with the oil. If solution gas cannot be conserved economically, it is usually flared.

Improving the conservation of solution gas from Alberta's producing oil wells continues to be a major emphasis for the ERCB. Between 1968 and 1990, the production of solution gas increased more than threefold, and the level of conservation went from 77 per cent to 90 per cent.

From a regulatory perspective, an important factor in having operators address the issue of solution gas recovery in a timely way has been the ERCB's gas-oil ratio (GOR) penalty base. This base provides for an automatic procedure whereby a penalty is applied against allowable production from an oil well until conservation issues, such as gas flaring, have been addressed by the operator. In some cases, the ERCB may also resort to flaring limits or shutting in oil wells in accordance with gas conservation orders.

Environmental concerns about solution gas flaring also have become more pronounced in recent years. The ERCB requires solution gas recovery unless an operator can clearly demonstrate that it is either uneconomic or technically impractical to conserve gas. When making such decisions, the ERCB carefully weighs environmental and aesthetic effects, as well as technical and economic matters. The Board will continue to work with industry to review gas conservation policies and to introduce changes as circumstances warrant.

Oil Sands

Syncrude Canada Ltd. ended 1990 with a record production of 9 million cubic metres of synthetic crude oil, up nearly half a million cubic metres from 1989. Suncor Inc. recorded its third-best year of production since start-up in 1967, producing about 3 million cubic metres of synthetic crude oil.

Throughout 1990, work proceeded on the design of the $4-billion OSLO (Other Six Lease Operators) commercial oil sands mining project. Addressing the many issues of such a massive project was the responsibility of the ERCB-initiated OSLO Application Review Team (OSLO ART) and its eight sub-committees. These groups include representatives from industry, federal and provincial governments, municipalities, and Aboriginal and special interest groups. This preparatory work is essential to resolve technical, environmental, social and Aboriginal issues in advance of a public hearing. OSLO ART plans to submit a major report and recommendations to the Board in the spring of 1991.

In December 1990, two commercial in situ projects, Esso Resources Canada Limited's Cold Lake Production Project and Amoco Canada Petroleum Company Ltd.'s Elk Point Project, announced expansion plans. In the first case, Esso will proceed with additional wells, facilities and pipelines required to tie in Phases 7 and 8 of its project. This expansion will add 3000 cubic metres per day of crude bitumen production to the Cold Lake project.

Esso received approval to build 150 steam injection wells and pipelines to expand its Cold Lake project.

Following public discussion of expansion plans in the summer of 1990, Amoco filed an application in December 1990 to construct Phase 2 of its Elk Point commercial oil sands project. The new scheme proposes to use both primary production and thermal stimulation to produce 2300 cubic metres per day of crude bitumen.

Additionally, the Amoco and Suncor Commercial Projects commenced testing of primary production potential in the Primrose Area. The encouraging results to date may lead to modified development plans using a combination of primary and thermal recovery methods.

Esso and BP now have plants that recycle the water used for raising the steam needed for several of their in situ production facilities.

BP Resources Canada Limited's Wolf Lake project commissioned a new water recycle plant in April 1990. Under new Alberta Environment/ERCB guidelines issued in 1989 to reduce freshwater requirements for in situ developments, BP's scheme is the second commercial oil sands project in Alberta to integrate a 100 per cent produced water recycle process.

Wide Range of Oil Sands Experiments Under Way

In September 1990, OSLO applied to the ERCB to scale up its earlier Dredging and Cold Water Extraction Process from a field test to a full-scale pilot project. Known as the Mildred Lake Pilot Project, this dredging and froth preparation process differs markedly from the hot water extraction method now in use at Suncor and Syncrude.

OSLO also operated a pilot plant at the Petro-Canada Inc. research facility in northeast Calgary, testing various water-based extraction processes. A Warm Water Extraction Process has now been selected for further testing.

Another experimental OSLO project relates to borehole mining in shallow oil sands. The 1990 project involved water-jetting four cavities some 10 to 20 metres below surface. If this technique is successful, it may provide a cost-effective way of recovering bitumen from shallow in situ deposits presently inaccessible by surface mining.

Also in 1990, Syncrude started the first phase of field trials to evaluate the feasibility of capping mature oil sands tailings sludge with natural water. Sludge capping is one of a number of reclamation strategies for oil sands tailings now being investigated by both Syncrude and Suncor.

Several experimental developments for in situ recovery methods continued in 1990. Chevron Canada Resources announced its Heated Annulus Steam-Drive Project, or HAS-Drive, north of Fort McMurray. Chevron proposes to use a combination of a heated horizontal well and vertical wells to recover crude bitumen from a 40-metre-thick formation 175 metres deep. Also in the Fort McMurray area, the Alberta Oil Sands Technology and Research Authority continued to develop its Underground Test Facility Project with the construction of additional tunnels in preparation for drilling six new horizontal wells.

In the Cold Lake area, Esso completed initial work on a borehole drilling scheme. In this experiment, a vertical well was drilled into a 30-metre-thick oil sands formation 500 metres below the surface. The drill bit was then replaced with a high-pressure water nozzle to create a large cavity, sending water and bitumen to surface through the well. The objective is to assess the economics of this method, since it may represent a higher recovery rate than the 20 per cent for steam injection techniques.

Air Quality Initiatives in Fort McMurray Area

The objective of providing an effective means to address air quality issues in the vicinity of the mineable oil sands plants north of Fort McMurray resulted in the 1987 formation of a Regional Air Quality Coordinating Committee (RAQCC). With representatives from industry, government and local communities, RAQCC provides a forum for the reporting, analysis, research and resolution of air quality issues in the Fort McMurray region.

In 1990, RAQCC put in place an Odour Response Protocol. With the support of Alberta Environment, operators and the ERCB, a team of technicians improved the method of tracking industrial odours, identifying their causes and working with operators on ways to reduce or eliminate odour problems.

A promising development in 1990 was Suncor's initiative to pilot test novel technology which, if successful, could reduce sulphur dioxide emissions. In November 1990 the ERCB approved the CANSOLV pilot project developed by Union Carbide Limited. Construction is expected to start early in 1991.

Natural Gas

ERCB Decides on Developer for Caroline Project

A major step in the development of the Caroline sour gas reservoir occurred in 1990 when the ERCB gave the nod to Shell Canada Limited's proposal to construct a sour gas gathering system and major gas processing facility.

The April 1990 hearing concluded almost 4 years of work during which the ERCB received competing applications from Shell and Husky Oil Ltd. During the month-long hearing held in the village of Caroline, the Board considered the applications from Shell and Husky as well as interventions from more than 50 community groups, municipalities, special interest groups, oil companies and individuals. The Board released its decision in favour of the Shell proposal in August 1990 and construction began in October.

Industrial Development Permits Up for 1990

The ERCB issued 6 new industrial development permits in 1990, several for producing feedstocks used in the manufacture of plastics.

After a quiet year in 1989, the Board issued 6 major industrial development permits in 1990, signalling renewed activity in this sector of Alberta's economy. The ERCB is responsible for permits for the use of Alberta's hydrocarbon resources in certain manufacturing and industrial operations. Additionally, the ERCB authorizes the use of energy to fuel energy-intensive industries such as cement plants and pulp mills. By the end of 1990, there were 40 such industrial development permits in effect throughout Alberta.

In a significant expansion of Alberta's ethylene industry, Dow Chemical Canada Inc. received a permit for the use of ethane and natural gas to produce ethylene at a new plant in Fort Saskatchewan scheduled to start up in 1994. Ethylene is a basic building block in the manufacture of many petrochemical products.

A joint venture by Neste Oy and Petro-Canada Inc. (the new company was recently renamed Alberta Envirofuels Inc.) also received a permit for the use of methanol, butanes and natural gas for the production of MTBE in a plant being built in Strathcona. MTBE is an additive used to enhance the octane rating of gasoline, replacing the use of tetraethyl lead which was phased out in 1990.

The ERCB also approved Daishowa Canada Co. Ltd.'s application to use natural gas as a supplemental fuel for its new bleached Kraft pulp mill at Peace River. Most of the mill's energy requirements will be met by burning wood wastes produced by the Kraft process.

The ERCB also dealt with several applications in 1990 for expanded facilities. The expansion of Union Carbide's ethylene glycol plant at Prentiss, Alberta, more than doubled the facility's current approved capacity. The ERCB also approved applications from a cement manufacturing plant at Exshaw and from an ammonia plant at Carseland.

The ERCB Implements Government's Ethane Policy

In 1990, the provincial government enacted legislation under the ERCB's Oil and Gas Conservation Act authorizing the implementation of the Ethane Supply Policy. The government developed this policy to ensure the availability of an adequate supply of ethane to large straddle reprocessing plants supplying the needs of Alberta's existing ethane-based petrochemical industry. As a result, the new provisions could restrict upstream extraction of ethane in the field by gas producers.

The ERCB issued Informational Letter IL 90-9 which outlines the procedures to be used to ensure the ongoing supply of minimum volumes of ethane to straddle plants. The ERCB also will review the volume of ethane expected to be available to straddle plants annually. After a call for submissions from industry, the Board issued its first forecast at the end of 1990. It appears that sufficient ethane will be available during 1991 to meet the minimum needs of straddle plants without diverting upstream ethane from the field processors.

The ERCB forecasts that Alberta's gas plants will produce enough ethane to meet the needs of straddle plants without diverting upstream ethane from field processors.

The ERCB Clarifies Gas Plant Proliferation Policy

There are more than 600 gas plants in Alberta, many with unused capacity. 1990 saw considerable progress in resolving the problem of gas plant proliferation.

In response to ongoing concerns about gas plant developments, the ERCB, late in 1989, requested industry input on ways of avoiding plant proliferation. At the same time, Alberta's Minister of Energy urged industry associations to address the matter of custom processing fees at Alberta's gas plants. (High custom processing fees caused some producers to apply to build their own processing facilities even though nearby plants had unused capacity.)

Industry responded by endorsing its own formula that will be the basis of negotiated processing fees (Gas Processing Fee Guidelines – JP-90). Additionally, this report suggests an arbitration process to settle disputes expediently. After further discussion with industry, the Board issued new guidelines early in 1991 to assist operators in avoiding unnecessary processing facilities. The Board is encouraged by the progress made in resolving these concerns and in applying these initiatives to new gas plant developments.

Alberta's Coal Seams Hold Potential for Major Gas Reserves

Currently, the ERCB is updating the ultimate gas potential for Alberta. Included in this review will be some preliminary estimates of the potential for non-conventional gas sources such as coal-bed methane. Extensive coal deposits in the province are both a reservoir for and source of methane gas, the result of millions of years of heating and compaction of vegetation.

The current interest in coal-bed methane stems largely from the early 1980s, when the United States introduced significant tax credits for the development of unconventional energy sources. An estimated 9000 coal-bed methane wells had been drilled in the U.S. to the end of 1990.

In Alberta, coal-bed methane development is still at an early stage of investigation. Nevertheless, environmental concerns have been raised about the closer spacing that may be required for coal-bed methane wells, the water usually produced with the gas and the possibility of such developments occurring in the Foothills and Mountains regions of the province.

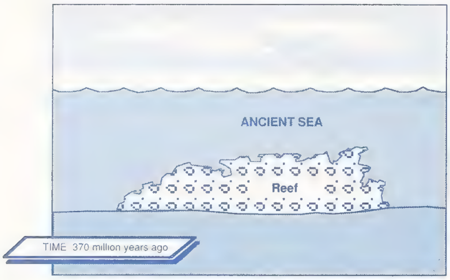
The Board expects a number of companies to look at small-scale coal-bed methane projects in a number of areas in the province. These will range from one to ten well-testing projects and will gather data on the quantity and quality of gas and water produced, as well as the long-term deliverability of the wells.

At the time of writing, a joint ERCB/Alberta Energy informational letter is being prepared describing the initial regulatory provisions to be applied to coal-bed methane developments. For now, existing gas well provisions will be applied to coal-bed methane production as much as possible.

Techno-focus #1

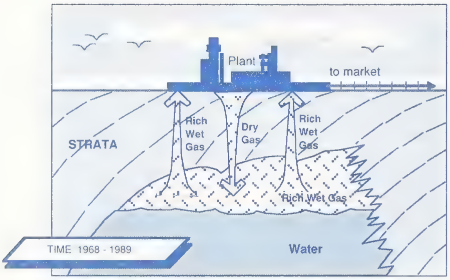
Blowdown: The Productive End of a Productive Era

As Alberta's energy industry matures, many older pools are reaching a final production phase known as "blowdown". For ERCB staff, assessing the technical merits of blowdown applications requires a careful balancing act: how to time the final removal of the resource in ways that conserve as much as possible, while keeping the economics reasonable.



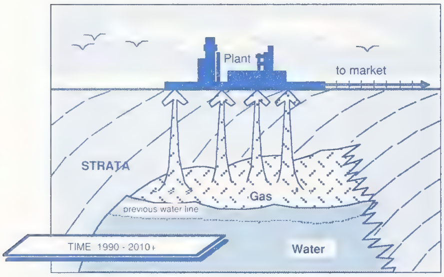
The ERCB's analysis of the Amoco and Chevron Kaybob South Beaverhill Lake A Pool, located 250 kilometres northwest of Edmonton, near Fox Creek, illustrates the challenge. Discovered in 1961, this 50-kilometre-long pool lies along the edge of a 370-million-year-old reef bank, now buried 3370 metres below the surface. The gas field is completely underlain by a large aquifer.

This massive field proved to be rich in "wet" gas, that is, gas abundant in condensates (naturally occurring hydrocarbons similar to refined gasoline) valued for their use in making gasoline and petrochemicals, and as a diluent for transporting heavy crude oil by pipeline.



By the late 1960s, conservation and economics dictated that a gas cycling scheme be implemented to increase condensate recovery from the field. Thus, as operators produced natural gas from the reservoir, the "wet" portions were stripped out. Most of the dry gas was reinjected into the formation to displace more "wet" gas and to reduce pressure depletion.

After 20 years of partial pressure maintenance through gas cycling, the reservoir pressure had gradually declined, allowing water to rise from the aquifer below. This posed a serious threat to further recovery, since water tends to bypass some gas as it rises, leaving behind "trapped" residual gas. Although all available gas could be produced quickly to avoid a permanent reduction in gas recovery, there would be a certain loss of condensate production.



After extensive technical discussions and a public hearing, in January 1990 the Board approved Amoco and Chevron's application to blow down the reservoir. A major condition of this approval was the operators' commitment to drill additional wells in the pool to produce "wet" gas from areas of the field where such production was still viable. The Board believed these extra wells also would ensure that gas would be removed from the reservoir as quickly as possible. Amoco and Chevron drilled eleven new wells into the pool during 1990. The field is expected to produce natural gas for another 25 years.

Ensuring the efficient recovery—that is, conservation—of Alberta's energy resources is an ongoing mandate of the ERCB. Each of the province's major pools has its own unique characteristics. As the pools reach the end of their normal productive lives, achieving optimum conservation may require the same sophisticated technology and careful controls that have been applied in the case of the Kaybob South Beaverhill Lake A Pool.

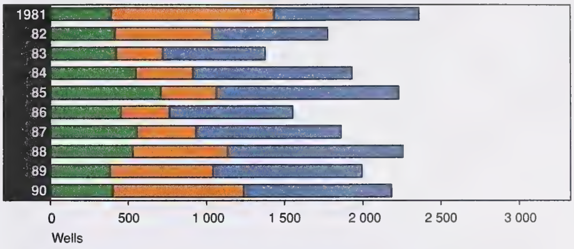
Alberta's Energy — A Historical Perspective

The following charts provide a 10-year perspective on Alberta's conventional oil, bitumen and synthetic crude oil, as well as natural gas and sulphur activities.

4. Oil and Gas Wells
Exploration

Exploratory drilling increased for both oil and gas in 1990, with increases in the number of successful wells by 5 per cent and 27 per cent respectively over the previous year.

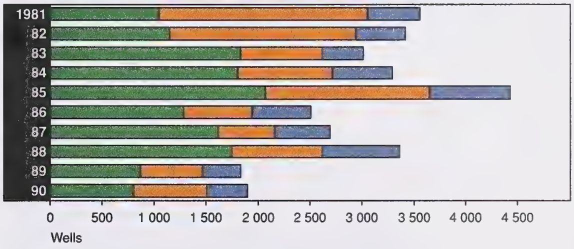
🟦 Abandoned and Other



5. Oil and Gas Wells
Development

While 1990 development drilling improved marginally from record low levels in 1989, activity continued to be sluggish. Development drilling for conventional oil continued to decline.

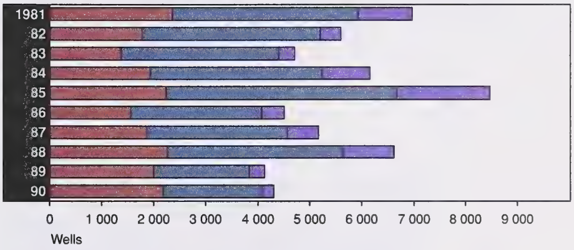
🟦 Abandoned and Other



6. Total Wells Drilled

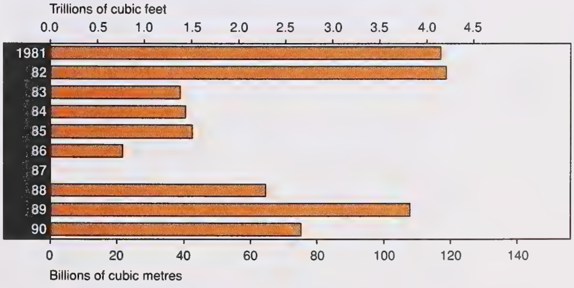
Although drilling was up slightly from 1989 levels, the total number of wells drilled in 1990 was still below the average for the previous decade.

🟥 Exploration
🟦 Development
🟪 Oil Sands



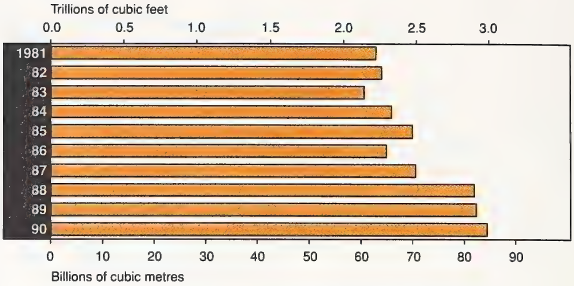
7. Additions to Established Gas Reserves

An estimated 75 billion cubic metres of gas reserves were proven during 1990, reflecting increases in exploratory drilling.



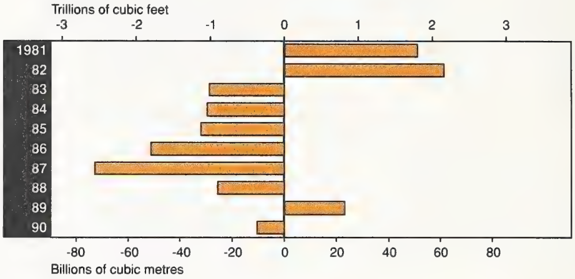
8. Gas Production

Gas production has been increasing gradually during the past 5 years.



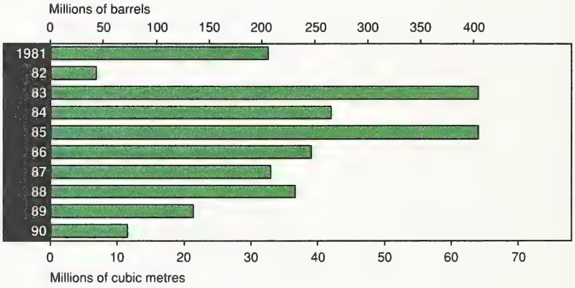
9. Changes in Remaining Established Gas Reserves

During 1990, reserves of natural gas were produced faster than they were discovered, resulting in a net decline of 10 billion cubic metres in established reserves.



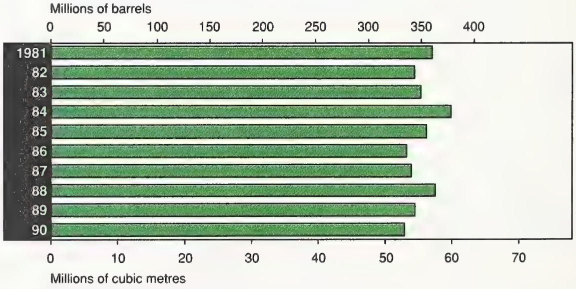
10. Additions to Established Oil Reserves

Additions to established oil reserves were an estimated 11.6 million cubic metres, down substantially from 1989. Most reserve additions came from heavy oil activity in east-central Alberta.



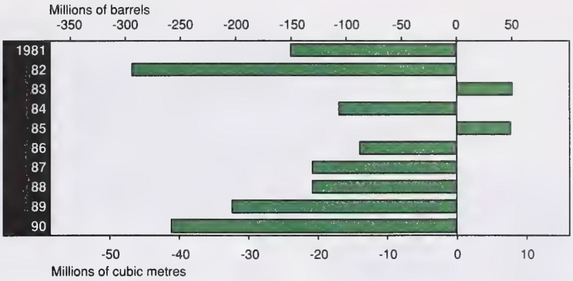
11. Conventional Oil Production

Conventional oil production was down slightly in 1990 despite higher world prices in the second half of the year.



12. Changes in Remaining Established Oil Reserves

Producers continue to dip into reserves to meet demands for oil, resulting in a net decline of more than 41 million cubic metres in established oil reserves.

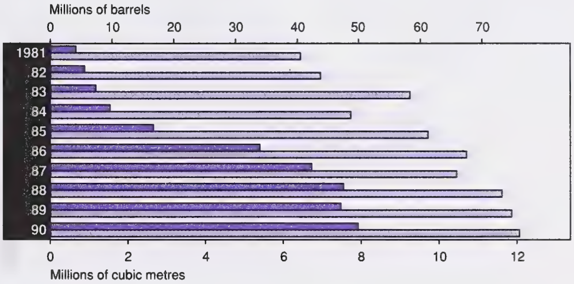


13. Bitumen and Synthetic Crude Oil Production

Record production from the Syncrude plant was responsible for the overall increase in production from Alberta's oil sands in 1990.

🟪 Bitumen

▨ Synthetic Crude Oil



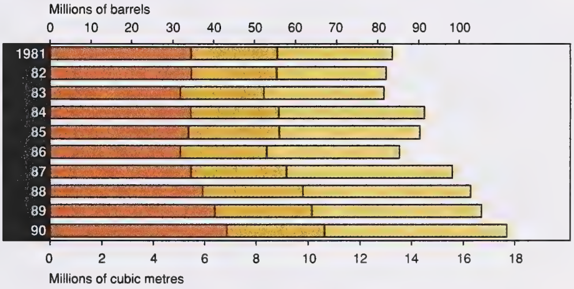
14. Natural Gas Liquids Production

Production of natural gas liquids, primarily used as petrochemical feedstock, has increased steadily for the past 5 years.

🟧 Propane

🟨 Butanes

🟨 Ethane

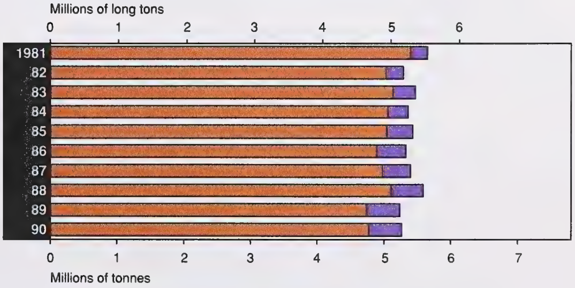


15. Sulphur Production

Virtually none of Alberta's 1990 sulphur production went into stockpile as offshore markets recovered from the problems experienced in 1989.

🟧 Gas Plants

🟪 Oil Sands Plants



Coal

Alberta's raw[1] coal production increased slightly in 1990 to 35.2 million tonnes from 35 million tonnes in 1989. Deliveries of marketable[2] coal declined from 30.8 million tonnes to 30.4 million tonnes because of reduced volumes going to Ontario Hydro as well as Japanese and Korean markets. This weakening coal demand resulted in workforce reductions at several of Alberta's export-oriented mines.

Alberta now has 11 major surface coal mines and a single underground mine.

On the development side, Cardinal River Coal Ltd.'s mine near Hinton and Luscar Ltd.'s Coal Valley mine near Edson applied to the ERCB to extend their existing mine permit boundaries to include three major new areas. These extensions are required to maintain continued coal production at existing rates over the next decade. The ERCB granted a similar boundary extension to Smoky River Coal Ltd. for its No. 12 Mine South, near Grande Cache.

Old Mine Plans Still Useful

When the ERCB's Coal Department received regulatory control of Alberta's coal mines in 1972, it inherited a large file of historical mine plans. This file has proven valuable in the planning and development of several tourism and recreation projects. In the Crowsnest Pass, for example, the Ecomuseum Trust recently rehabilitated a portion of the old Bellevue Mine for underground public tours. A similar project is now under consideration at Nordegg. In addition, developers of a major golf complex planned for the Canmore Mines property made extensive use of these plans.

Underground Research Project at Grande Cache

A continuing project during 1990 was the thick-seam mining demonstration at the underground mine of Smoky River Coal at Grande Cache. This project is designed to assess the technical feasibility of an integrated mining system capable of extracting coal seams in excess of 3.66 metres (12 feet) thick in a single pass. As part of this initiative, members of the project's Technical Advisory Committee—of which the ERCB is a part—toured South Africa, Australia and Austria to view and assess equipment that may be included in this project.

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[1] *Unprocessed coal as loaded in the mine, also known as run-of-mine coal.*

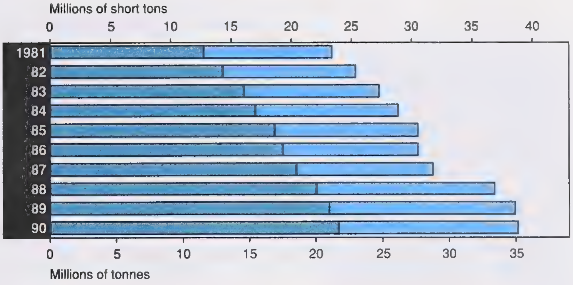
[2] *Subbituminous raw coal and bituminous raw and clean coal (processed product with a uniformly low ash content) delivered to market.*

16. Coal Mine Production (Raw Coal)

Raw coal production was unchanged from 1989. Production of thermal coal used for generating electricity in Alberta increased somewhat, while export coal production dropped slightly.

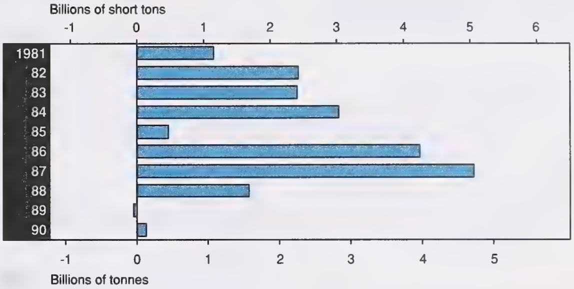
▨ Subbituminous

▨ Bituminous



17. Changes to Remaining Established Coal Reserves

Most exploration is concentrated around producing mines to replace depleted reserves. Alberta's current coal reserves remained unchanged at 32 gigatonnes.



Electricity

The province's electric utility companies had an active year in 1990. At the Genesee Power Plant, Edmonton Power resumed construction of the boiler for the plant's second unit. After a number of delays, suppliers completed the manufacture of the boiler and construction got under way. Existing and future electric energy requirements will be monitored to determine an appropriate completion date for the unit.

Electric energy requirements will be monitored to determine the completion date for the Genesee Power Plant.

Alberta Power Limited commissioned a second 366-MW coal-fired generating unit at the Sheerness plant in November 1990, bringing total plant capacity to 746 MW. The plant is jointly owned with TransAlta Utilities Corporation.

Also, in November 1990 the ERCB approved a proposal by The City of Medicine Hat to expand its power plant by adding two 17-MW gas turbine units in 1993 and a 30-MW steam turbine unit in 1996. In response to the Board's August 1990 decision that Medicine Hat delay an immediate expansion, the City reached an agreement with TransAlta Utilities to utilize surplus electric generating capacity on the province-wide electric system. As a result, Medicine Hat was able to defer its original expansion plans at a cost-saving to the City and other Alberta consumers.

The year 1990 also saw a number of 138-kV transmission lines added to the provincial electric system. Notable was Alberta Power's plan to construct such a line from Rainbow Lake to the Alberta-B.C. border to interconnect with a transmission line in British Columbia. This project will permit energy generated in Alberta to be used in the remote northeastern B.C. community of Fort Nelson. Fort Nelson is isolated from B.C.'s electric system and until now has been dependent upon high-cost oil and gas-fired plants for its electricity.

Power transmission systems are just one component of the planning now under way for Alberta's electrical future.

Electricity Generation Planning Parameters Under Review

How many power plants will be needed to provide electricity to Albertans at a level of reliability and cost they have grown to expect? This is the question the ERCB, Alberta's electric utilities and other interested parties tried to grapple with during a major review of electrical planning parameters begun in 1989.

Following a public review, the ERCB agreed with major utilities that more study was required to determine appropriate parameters for the longer term. The ERCB's report also identified planning criteria to be used in the interim.

Alberta's Electric Utility Planning Council, representing stakeholders from the province's electrical industry, is undertaking the long-term study. It will address such specific issues as these: What is an acceptable level of reliability for Alberta's electrical system? How should utilities determine peak ratings for existing generating plants? And, to what extent should Alberta rely on its interconnections with B.C. Hydro and Saskatchewan Power Corporation to provide reserve capacity? The ERCB expects the study to be completed by the end of 1991.

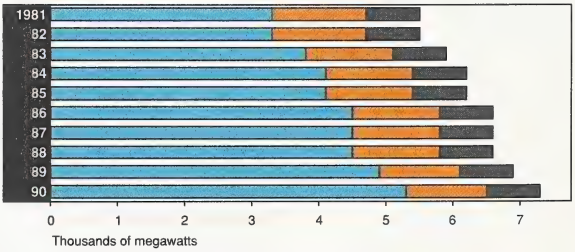
Small Power Developments

During 1990, wind plants in southern Alberta generated the province's first kilowatt-hours of electric energy under the provincial government's Small Power Program. (There were earlier wind projects, but these were operated independently of the program.) Established in 1988, the program encouraged electric generation by small power producers by allowing them access to the province-wide electrical grid and providing them with a predetermined, fixed return for the energy they produce.

The ERCB also approved several other proposals under the program. Engineering work got under way in 1990 for a small hydro power plant at Dickson Dam on the Red Deer River. The ERCB expects construction to begin early in 1991. Additionally, the ERCB authorized several small hydro plants at irrigation structures in southern Alberta, a used-tire-fired plant at Trochu, and a wood-waste-fired plant near Whitecourt.

18. Electric Generating Capacity

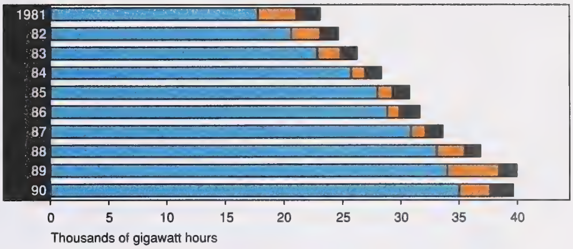
The start-up of coal-fired units at the Sheerness and Genesee power plants brought an estimated 6 per cent increase in Alberta's generating capacity.



19. Electricity Generated

For the first time in years, there was no growth in production from Alberta's electric generating facilities, despite increased capacity.

■ Hydro



Pipelines

New Procedures for Assessing NOVA Pipeline Applications

This Cochrane, Alberta construction site was part of NOVA's continued pipeline expansion program for 1990.

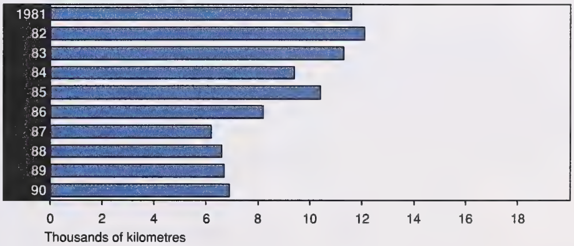
NOVA Corporation of Alberta, which operates the provincial transmission and gas-gathering network, continued its major expansion program during 1990. New facilities are required to meet the growing potential for new gas sales in Canada and the United States in coming years.

To ensure that expansion plans receive appropriate regulatory review, the ERCB initiated a study in consultation with industry to evaluate what review procedures and economic criteria should be used for assessing NOVA applications. The new guidelines were published in Informational Letter IL 90-8 entitled "Procedures for the Assessment of NOVA Pipeline Applications–Industry Review".

The new procedures promote a more efficient and timely exchange of information among industry parties through a committee established by NOVA for this purpose. The new process also requires NOVA to file an annual preliminary plan of its overall system, showing all planned facility additions or major modifications. As work progresses on individual items in the plan, NOVA will submit final information on the technical, cost, route siting, land considerations and environmental assessments required to complete each application. The ERCB continues to deal with landowner/occupant and environmental concerns according to established regulatory procedures.

20. Pipelines Installed

The addition of 6900 kilometres of new pipelines in 1990 brings Alberta's total pipeline network to 208 200 kilometres.



Major Pipeline Failure Captures Public Attention

An event which attracted much public attention during 1990 was the accidental release of 2300 cubic metres of oil into a muskeg area near Rocky Mountain House in early June. The release resulted from the failure of a 114-millimetre (4-inch) pipeline belonging to Amoco Canada Petroleum Company Ltd. After a lengthy investigation to determine the cause of the break, the Board issued ERCB Report 90-C in October showing that the pipe failed because of stress corrosion cracking influenced by an unusual, and largely unpredictable, combination of factors.

Amoco has since implemented a follow-up investigation to see if similar faults exist elsewhere on the pipeline and found no further indication of the stress corrosion cracking phenomenon. Amoco is also proceeding with the installation of an automated monitoring capability on the entire system.

As a result of the Amoco failure, the ERCB initiated the formation of a joint industry-ERCB Task Force to review the need for refinements to the ERCB-endorsed Leak Prevention and Detection Recommended Practice presently in use by operators. This work is expected to be complete by the spring of 1991. The Task Force also will address the need for retroactive application of the Recommended Practice to existing pipelines.

Amoco initially subjected the spill site to intensive clean-up and reclamation efforts. The ERCB and Alberta Forestry, Lands and Wildlife will continue to monitor the site and Amoco's ongoing reclamation program until all necessary work is complete.

The ERCB Approves Alberta's First Liquid Sulphur Pipeline

One of the most convenient ways to ship sulphur is in pellet form. Production from Alberta's first-ever liquid sulphur pipeline will be pelletized.

As part of Shell Canada's application to process sour gas from the Caroline Field, the ERCB approved the company's plans to transport up to 8000 tonnes per day of liquid sulphur by pipeline from its new plant to the Shantz Forming Facility. At this location, the sulphur will be made into pellets and transported by railway to Vancouver for shipping to world markets. The pipeline eliminated the need to construct a costly and controversial rail spur line into the Caroline area.

Liquid sulphur pipelines are rare, and Shell's promises to be unique both in design and operation. For example, the 40-kilometre pipeline will consist of an inner 219.1-millimetre sulphur pipeline encased in a 323.9-millimetre hot water pipeline which, in turn, will be surrounded by a layer of insulation, capped by a layer of polyethylene. This final barrier will protect the insulating layer from groundwater.

The greatest challenge for pipeline designers will be to keep the sulphur liquid. The line will operate at between 122 and 155 degrees Celsius, but because of the insulating layers, the soil next to the pipeline will experience temperatures of about 20 degrees Celsius. Should the hot water system fail, the sulphur would have to be purged from the line quickly since sulphur solidification is calculated to start about 10 hours after a system shut down. Heater stations at either end of the line–with back-up capability–will use steam and glycol heat exchangers to continuously maintain the high operating temperatures of the hot water portion of the line. Liquid sulphur is neither sour nor toxic and is considered a non-corrosive substance. Although this presents less of a problem if a leak occurs, hot water volumes will be measured on an ongoing basis to detect leaks quickly.

Techno-focus #2

What Does Your Toaster Have in Common with Pipeline Components?

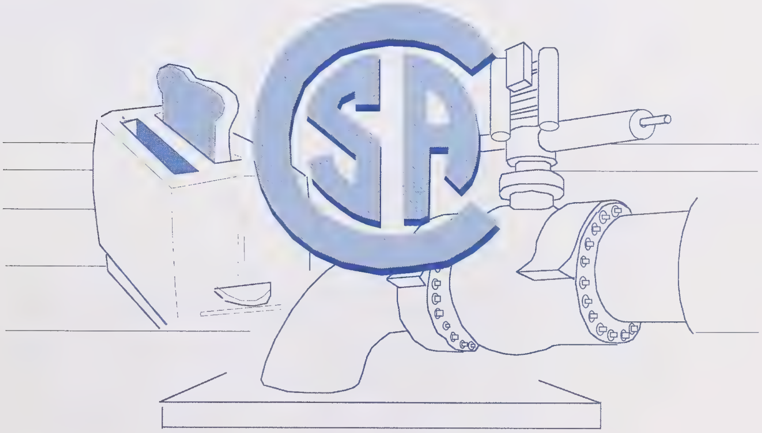
Both must be certified by the Canadian Standards Association (CSA). Most of us recognize the familiar CSA logo on household electrical appliances. Virtually unknown, but as important to public safety, are the CSA standards that apply to Canada's pipeline industry. The CSA is a not-for-profit, non-statutory, voluntary membership association engaged in standards development and certification activities.

The process of producing pipeline standards is detailed and careful. The Standards Steering Committee, made up of senior industry and regulatory representatives, is a policy-making body which oversees the work. A Technical Committee votes on each specific clause in the standards, usually by a balloting process. Thirty committees and work groups carry out the detailed work of recommending new standards.

For example, before a standard can be published, it requires approval by two-thirds majority of the Technical Committee and 60 per cent of the Steering Committee. All negative ballots must include reasons so that committees can work to resolve any concerns. On contentious issues, committee members work towards consensus. This implies much more than a simple majority, but not necessarily unanimity. One result of this work is that Canadian pipeline standards are highly regarded internationally.

Under Alberta's Pipeline Act and Regulations, the ERCB could set its own detailed requirements for the design, construction, operation and maintenance of the province's pipelines. Instead, the ERCB finds it more efficient to utilize the standards published by the Canadian Standards Association. These are now part of the ERCB's Pipeline Regulations.

The ERCB is represented at each level in the process, and participation is part of the regular work of the engineers and senior technicians of the Pipeline Department.



Sales and Distribution

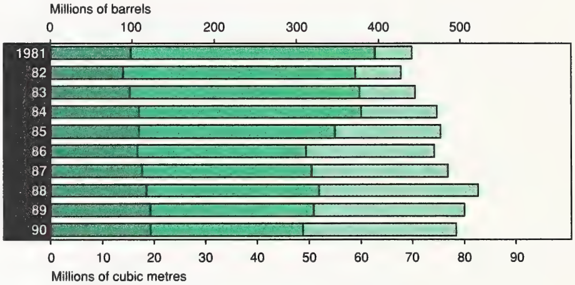
Sales volumes of Alberta's fossil fuel resources showed a slight increase from 1989 levels. Oil sales were down because of lower conventional oil production, while sulphur sales regained pre-1989 levels.

Overall production of crude oil and equivalent declined by some 2 per cent. Quebec and Ontario refineries reduced their receipt of Alberta oil in favour of U.S. and offshore sources of supply. Movements of oil into Alberta's other markets, such as the western provinces and the northwestern and midwestern U.S., remained stable. (See Figures 21 and 22.) There was no growth in the volume of oil refined in Alberta compared to last year, the result of a major maintenance shut-down at Petro-Canada's Strathcona refinery in Edmonton during the summer.

21. Markets for Oil and Equivalent

Alberta's decline in oil production resulted in reduced deliveries to markets in eastern Canada, while sales to U.S. markets increased slightly.

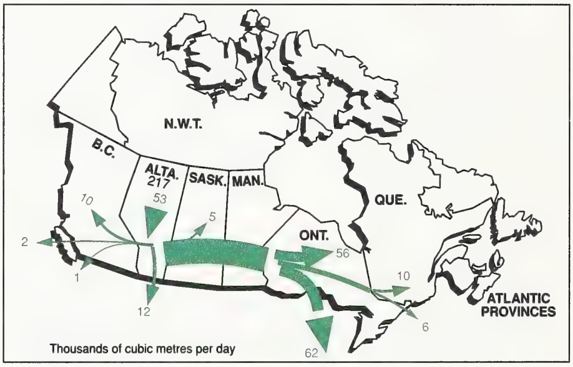
🟩 Alberta
🟩 Other Canada
🟩 U.S.A.



22. Markets for Oil and Equivalent in 1990

The shut-down of Edmonton's Petro-Canada refinery during the summer of 1990 accounted for the reduction in Alberta's overall use of oil during the year.

Legend
Production
Deliveries



Alberta's production of marketable gas showed little change in 1990, partly because of growing competition from natural gas supplies from Saskatchewan in eastern Canadian markets. Another minor factor was the soft demand for some types of petrochemicals that use natural gas as a feedstock. The volume of Alberta gas sold to Ontario and Quebec customers was unchanged from 1989 levels, while sales to U.S. markets increased by less than 2 per cent.

Sulphur sales during 1990 showed an 8 per cent increase over record-low levels in 1989. Last year's problems were caused by a contractual dispute between India and Morocco, which in turn triggered a downturn in Alberta's sulphur exports. As Figure 25 indicates, sulphur sales in 1990 returned to average levels for the past decade.

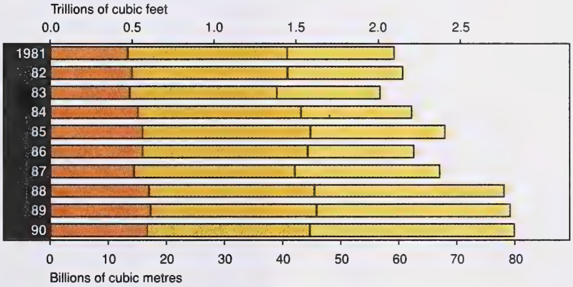
The present level of sulphur sales–just over 6 million tonnes–is in line with historic sales levels. This 1990 sales volume meant that about 1 million tonnes of sulphur were removed from Alberta's block inventory.

Coal sales declined by about 1 per cent in 1990, with most of the decline attributable to lower sales of bituminous coal to Alberta's two main customers, Ontario and Japan. The volume of subbituminous coal consumed in Alberta to generate electricity increased slightly from 1989. (See Figures 27 and 28.)

23. Markets for Gas

Increased gas sales to the U.S. Midwest offset reductions to customers in Ontario, Quebec and Alberta.

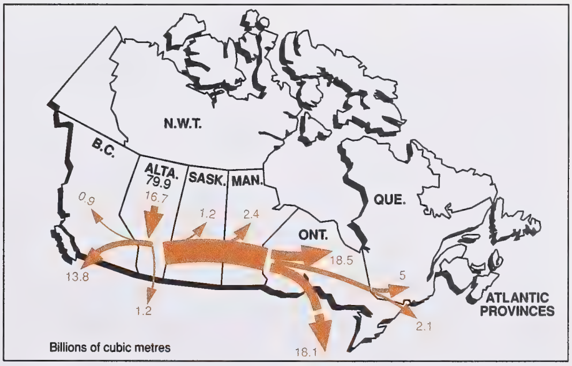
▨ Alberta
▨ Other Canada
▨ U.S.A.



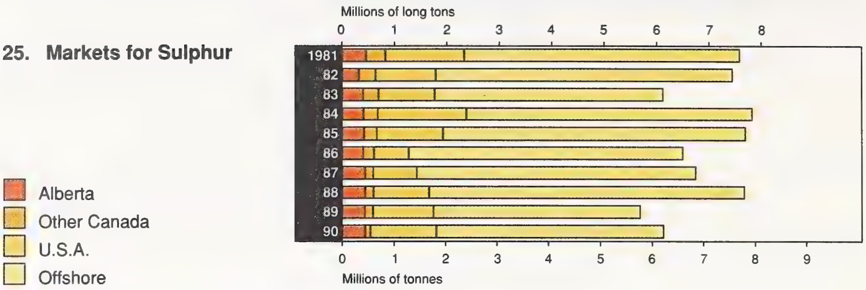
24. Markets for Gas in 1990

Sales of Alberta gas to Ontario, traditionally a major customer, declined in 1990 because of competition from Saskatchewan suppliers.

Legend
Production
Deliveries

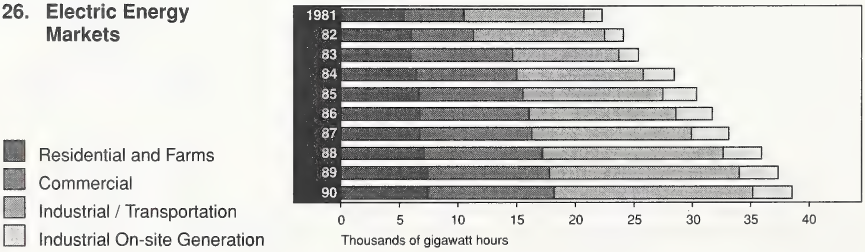


25. Markets for Sulphur



If 1990 levels of sulphur sales continue, producers will continue to draw from block inventory to meet demand.

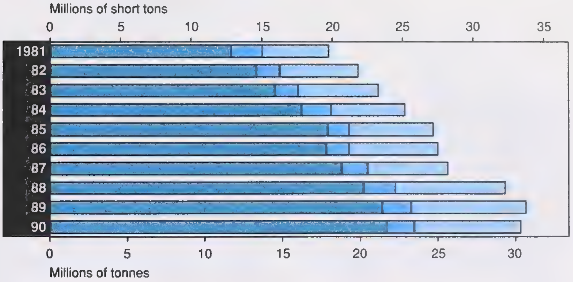
26. Electric Energy Markets



27. Markets for Coal

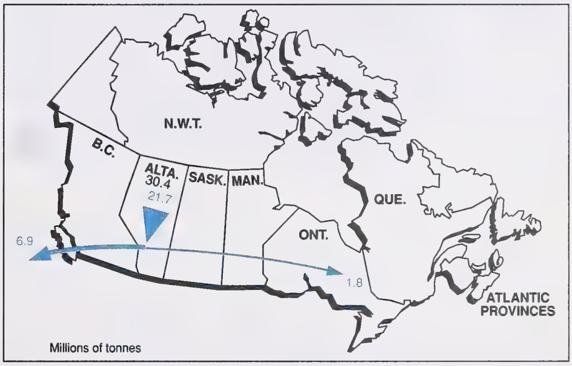
Reductions in coal deliveries outside Alberta offset the modest increase in Alberta consumption.

▨ Alberta
▨ Other Canada
☐ Offshore



28. Markets for Coal in 1990

Legend
Production
Deliveries



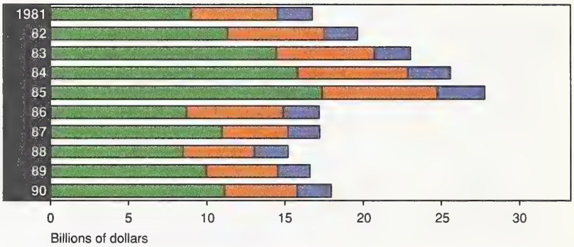
Alberta coal, bound for Pacific Rim markets, moves by rail to the Roberts Bank bulk handling facility in B.C.

Revenues, Investment, Employment

Sales Revenues

Activity in Alberta's energy industry has a major effect on the province's economy. Energy sales to other parts of Canada and the U.S. comprise a major part of the province's income. This revenue permits Alberta-based energy companies to continue to add to their asset base within the province, thus directly employing Albertans and creating a demand for a large supply and service sector to support energy production activities. Furthermore, a significant amount of the total revenue generated by the energy sector goes to provincial and municipal governments in the form of royalties, licensing fees, and income, property and business taxes. Thus, the economies of many towns and cities are closely linked to the fortunes of the energy industry.

Alberta's energy industry creates the need for a large supply and service sector.



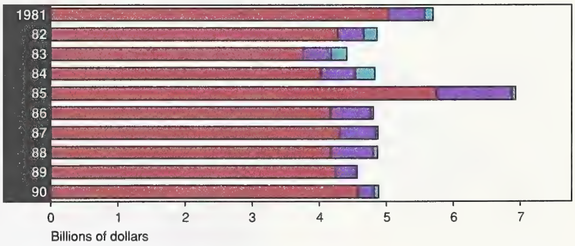
29. Gross Revenues
All Hydrocarbons

The total sales value of Alberta's energy resources and sulphur was an estimated $18 billion in 1990, about 8 per cent higher than in 1989, the result of improved oil prices in the second half of the year.

▨ Other

Investment

Retained earnings from profits traditionally have been the primary source of funds for reinvestment in the energy sector, although some funding comes from stock issues for private investment. The 1990 levels of external financing—the funds raised from private investors—were about half 1989 levels, but still above average for the past decade. This recent drop is not as significant as it may first appear because much of the 1989 funding was used for acquisitions and mergers, rather than being directly invested in the exploration and development of new reserves. The high level of acquisition activity seen in 1988 and 1989 subsided in 1990.



30. Energy Investment in Alberta

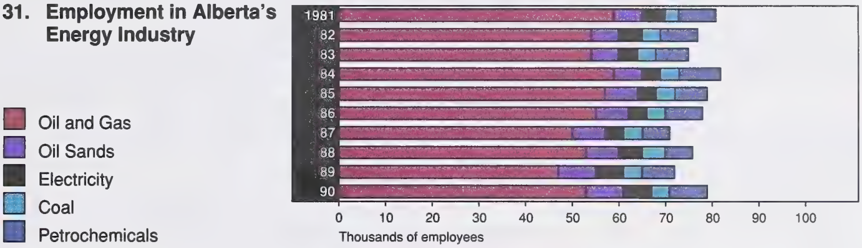
Acquisitions and take-over activity subsided in 1990 in favour of more direct investment in exploration and development.

🟥 Gas and Conventional Oil
🟪 Oil Sands
🟦 Coal

Employment

Although the ERCB does not keep its own employment statistics related to the province's energy sector, estimates for 1990 seem to indicate a modest increase in direct employment during the year. While sectors such as oil sands and electricity showed little change from 1989, employment in the coal industry declined slightly. Most growth appears to have occurred in the oil and gas and petrochemical industries. Several large oil companies have recently announced major lay-offs, which will likely be reflected in the employment picture for 1991. In addition, there appears to be some evidence that medium-sized companies "staffed up" to take advantage of relatively stable market opportunities for petroleum resources.

31. Employment in Alberta's Energy Industry



While most investment funding for the energy sector comes from corporate revenues, some is raised from stock issues, including those listed on the Alberta Stock Exchange, pictured here.

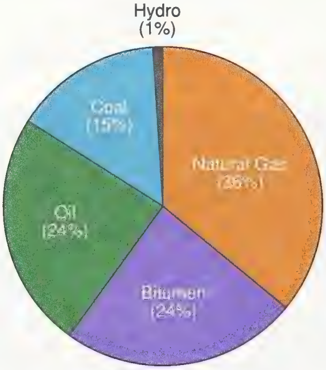
Meeting Energy Demands

Alberta markets its fossil fuel resources and their by-products within the province, across North America and around the world. Almost all of Alberta's energy requirements are met from the province's own hydrocarbon reserves. Figure 32 shows the energy resources used to meet Alberta's internal requirements in 1990. The relative "draw" of each end-user sector on the province's total energy consumption is shown in Figure 33.

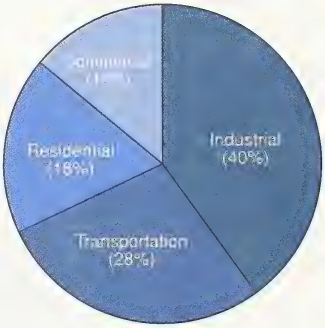
As Figure 32 indicates, natural gas supplies the bulk of Alberta's energy demands. For example, gas accounts for most of the energy used in residential and commercial heating. Gas is also a key ingredient in the province's petrochemical industry, providing a valuable feedstock for the production of nitrogen fertilizers and the ethylene used in the manufacture of plastics.

Alberta's electric utilities consume about 70 per cent of the coal produced in Alberta, with the remainder going to markets in Ontario and offshore. On the oil sands front, more than two-thirds of Alberta's bitumen is refined at two upgrading plants in Fort McMurray. The remainder is used for making asphalt and tar for shingles, roofing and other waterproofing materials, or is exported to refineries in Ontario and the United States.

32. Energy Resources to Meet Alberta's End-use Requirements: 1990



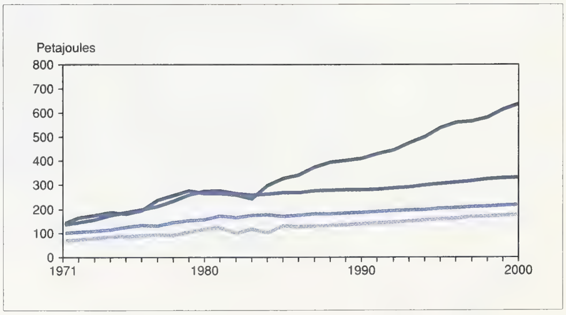
33. 1990 End-use Requirements in Alberta



34. Secondary Energy Requirements by Sector

Alberta's industrial sector included energy-intensive operations such as petrochemicals, oil sands and pulp and paper.

■ Industrial
■ Transportation
■ Residential
■ Commercial



The industrial use of energy in Alberta—as the ERCB defines it—includes not only the power required to run manufacturing processes such as pipe-making, paper production and food processing, but also the energy required to make energy and energy products. For example, the massive bucketwheel excavator and conveyor system at the Syncrude mine uses a great deal of energy. It takes the energy equivalent of 1 barrel of oil to produce 10 barrels of synthetic crude oil at an oil sands mining operation, excluding feedstock.

Alberta's oil refineries process crude oil to make a variety of fuels which leave the province for markets throughout western Canada. These fuels make up one of the main components of the transportation sector, as shown in Figure 33. Natural gas also figures into this picture of transportation end-use requirements as the resource used to power compressors on gas pipelines, and in propane or liquid natural gas-powered vehicles.

Over the next decade, the residential, commercial and transportation sectors are expected to show modest growth, as shown in Figure 34, to keep pace with trends in population growth. Continued improvements in the efficiency of energy use by consumers also appear to be influencing this more gradual rise in energy demand.

The industrial sector, however, remains the largest single consumer of energy in Alberta and, as shown in Figure 34, is expected to grow at the fastest rate, largely on the strength of increased petrochemical processing, pulp and paper projects and rising bitumen production.

Thermal electric generating facilities, such as the Sundance Plant west of Edmonton, consume about 70 per cent of the coal produced in Alberta.

Alberta and the Future Canadian Energy Picture

Despite consistently high levels of energy exports from Alberta, the province still contains a large proportion of Canada's total reserves of energy resources, as shown in Figure 35. From a national economic perspective, Alberta's resources are being produced at sustained levels because they are generally cheaper than Canada's reserves in the far north or off the Atlantic coast.

The total production of oil and equivalent, which includes synthetic crude oil (see Figure 37), is expected to remain fairly constant over the next 15 years. The decline in conventional light and heavy crude oil is expected to be replaced by increased production of bitumen and synthetic crude oils. This general decline of light, low-sulphur crude oil is by no means unique to Alberta, but is a worldwide phenomenon.

To offset this declining supply of light crude oil, high-quality crude oil refiners in Alberta, Ontario and the American Midwest will have to invest in facilities that permit the use of lower quality crude oils as feedstock. In the interim, eastern Canadian refineries are using offshore crude oils. As part of this changing crude oil supply picture, the Sarnia-to-Montreal leg of the Interprovincial Pipeline, which carries crude oil from Alberta to eastern Canada, operated at minimal capacity during 1990. Industry and government are presently investigating a proposal to shut down the line between Sarnia and Montreal or, perhaps, to reverse the flow of the line in the long term. While the reliance on imported oil likely will grow in eastern Canada, Alberta refiners will have enough local crude oil feedstock to continue to supply the refined products in the province for many years to come.

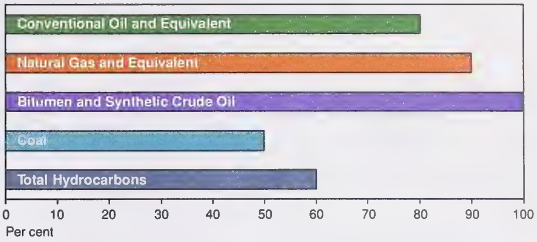
Albertans can expect to enjoy plentiful supplies of natural gas well into the next century, as shown in Figure 38. In addition, the province's ability to broaden its markets will also grow in the next decade.

These oil and gas supply forecasts reflect only general trends, and do not recognize the potential effects of new technologies and innovation. For example, just as enhanced recovery in the 1960s increased reserves, so the long-range effects of horizontal drilling and coal-bed methane on future supplies have yet to be determined.

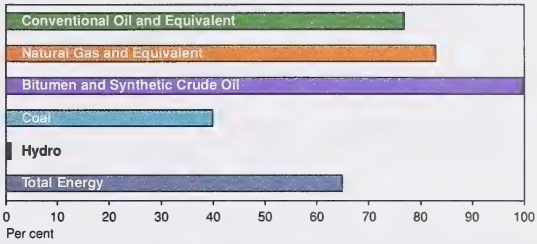
One component of Alberta's transportation end-use is the crude oil used by refineries to make fuels for cars, trucks and airplanes.

35. Alberta's Proportion of Canada's Energy Reserves

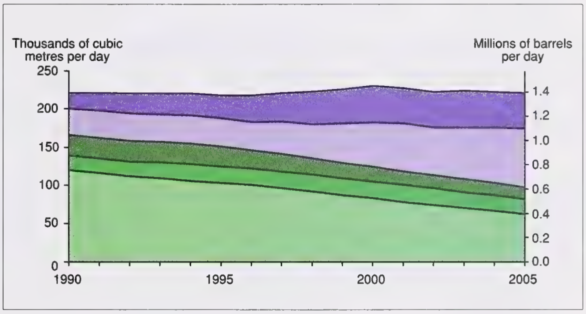
High levels of energy exports from Alberta have not significantly reduced the province's proportion of Canada's total reserves of energy resources.



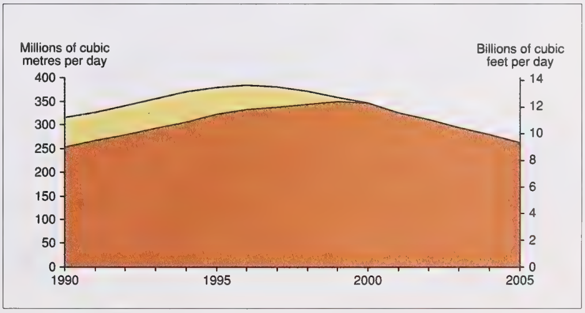
36. Alberta's Proportion of Canada's Marketable Production



37. Oil and Equivalent Supply to 2005



38. Gas Capacity and Production to 2005

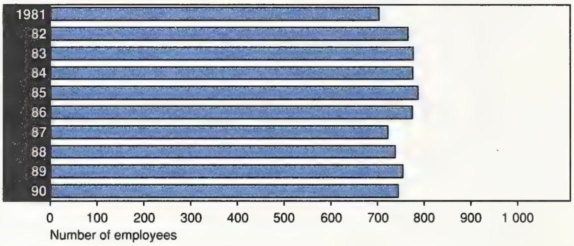


ERCB Operations

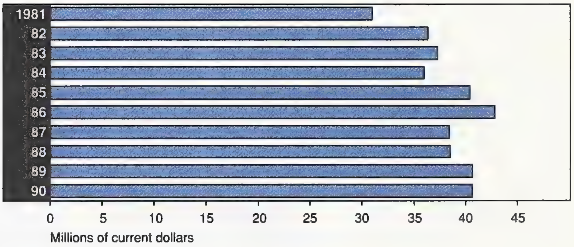
This section of ***Energy Alberta*** reports on major regulatory projects undertaken by the ERCB in 1990. One important aspect of these initiatives is the ERCB's continued reliance on industry as a whole to provide the time, resources and skilled people to assist in the development of effective regulations. In trying to anticipate such issues, the ERCB continues to work on resolving problems associated with such matters as orphan wells, inspection priorities and abandoned production batteries.

The ERCB is also encouraged by the movement towards more effective public involvement. In this regard, this section of ***Energy Alberta*** outlines two important public safety initiatives: the sour gas emergency response system and the results of a 4-year sour gas risk study.

39. ERCB Staff



40. ERCB Expenditures



1990 Staffing and Expenditures

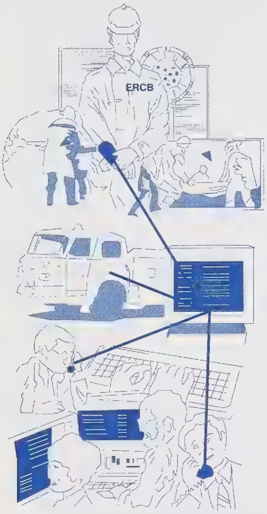
The ERCB continues to exercise vigilance in controlling spending and improving efficiency. This theme is reflected in the ERCB's efforts to automate its Core Research Centre, and the completion of two major geological computer systems. Additionally, the ERCB's employee count decreased from 755 in 1989 to 745 in 1990.

The ERCB's 1990 operating budget of $40.6 million remained the same as in 1989. Stated another way, the cost of regulating Alberta's energy sector represents 3.14 cents per oil equivalent barrel of energy production.

Techno-focus #3

Responding to Energy Emergencies Requires Strict Organization and Careful Communication

Imagine this scenario: during routine servicing, a company truck damages the main control valve on a sour gas wellhead. The sickly smell of rotten eggs spews from the well and drifts with prevailing winds. Within minutes, the crew radioes headquarters about the accident. Within half an hour, the company's site-specific emergency response plan is in full operation.



Meanwhile, the operator contacts the nearest ERCB field office. Staff there immediately activate the provincial sour gas emergency response plan which will involve numerous government agencies and departments. The top priority is public safety; the second is to gain control of the well. Behind the scenes is a proven communications network and a well-established information system.

The technology to ensure public safety combines telecommunications and face-to-face contact. The telephone is one of the most important tools. In this case, the company promptly alerts four families living in the immediate area, advises them of a possible threat to their safety and requests that they move to a nearby evacuation centre.

As soon as the ERCB determines that this incident has the potential to become a serious sour gas emergency, it triggers the implemention of a Main Control Headquarters (MCHQ). The telephone company is alerted to set up an emergency communications system. Within a few hours, technicians will have a bank of telephone lines fully operational in a headquarters that will house more than 20 technical and communications professionals.

Mobile communications technology also plays a key role. Systems in place ensure that someone on the ERCB's on-call emergency response team can be reached around the clock. Meanwhile, at the incident site, an ERCB field inspector reviews the situation firsthand, keeping in constant contact with the office via mobile phone.

Computer-based information is another essential component of the provincial emergency response system. In that first critical period, a computer based at ERCB headquarters in Calgary and linked to all eight ERCB field offices tells staff what they need to know about the well: when it was drilled, who owns it, how deep it is and its producing formations. The well's hydrogen sulphide content, maximum flow rates and pressures, and often the configuration of surface equipment, are also readily available from the ERCB's records.

As the emergency progresses, operator and regulator will use this information and input from many experts to assess, approve or modify the company's decisions about how best to regain control of the well and safeguard the public. They will also think through the "what ifs" and work with the inevitable uncertainties.

Accidents and incidents are rare in Alberta's busy oilpatch. The combination of up-to-date information, the latest telecommunications systems, and human experience should reassure Albertans that any emergency will be resolved quickly and safely.

New Inspection Manual for Production Batteries Under Way

In a 1990 initiative by the ERCB's Field Operations Department, staff finalized a new inspection manual for operators of production batteries. The draft manual has been circulated to industry associations for review and comment. Seminars are scheduled for mid-1991 to provide guidance to operators on the specifics of doing their own comprehensive inspections.

The publication will explain what ERCB regulations mean in practical situations. As an example, operators will be able to work with the same checklist used by ERCB inspectors when analysing requirements for such things as dikes, signs, noise levels, equipment spacing and measurement.

The ERCB believes that improved communication with operators is the key to improving operations at production batteries. For its part, the ERCB is preparing this manual, the third in a series of inspection manuals. The first two dealt with drilling rigs and service rigs. With the widespread use of these manuals, ERCB inspectors have found province-wide improvements in performance, while actually spending less time doing the related inspection work.

ERCB communication with operators has been key to improving operations.

Orphan Wells—Regulation or Co-operation?

Orphan wells are essentially wells with no owners, and little or no value, that have not been properly abandoned. Such wells can pose an environmental threat to either surface or underground aquifers and all orphan wells must be properly abandoned. The costs of this work can be significant and, until recently, were paid from the interest generated by an abandonment fund established by industry and government and administered by the ERCB.

The ERCB began to review the entire orphan well situation several years ago. Late in 1989, the Board set out for discussion a number of changes to regulations that would focus responsibility for abandonment on those who had benefitted directly from the well, that is, on industry. Since these proposed changes had the potential to affect the way operators do business, industry representatives proposed several modifications and alternative approaches to the problem in 1990.

The Board is reviewing these proposals and negotiations continue. The result of this process most likely will involve changes to regulations and an innovative approach to financing that will allow industry as a whole to fund the solution of the problem of orphan wells. In other words, regulation and co-operation.

In the interim, the ERCB is co-ordinating its internal work to prevent additional orphan wells and ensuring the proper abandonment of existing ones.

Inspectors Tackle Abandoned Production Batteries

During 1990, the ERCB's Field Operations Department made a concerted effort to locate and identify owners of derelict production batteries. A battery is a central gathering location to collect, treat and temporarily store oil before it is transported to a refinery.

An abandoned production battery often becomes an eyesore and a nuisance to farmers. Although the landowner may still be receiving compensation for the surface lease, the ERCB is concerned about the larger issues of public safety and returning the land to its original use. The ERCB's objective is to ensure that old, inactive surface facilities are removed to prevent the possibility of fluid leaks, that connecting pipelines are properly purged and that the land and access roads are returned to their original state.

ERCB inspectors worked on more than 30 such facilities during the year, most of them located in the older, depleted oilfields in central Alberta. In addition, the ERCB requested many other owners of improperly abandoned batteries to submit clean-up and reclamation plans.

ERCB Releases Results of Major Sour Gas Study

Alberta is a major supplier of natural gas to North Americans, and is one of the world's leading exporters of sulphur. Both activities rely on producing the province's massive natural gas reserves, and these often contain hydrogen sulphide or sour gas.

Recognizing the growing concerns about the risks associated with sour gas accidents such as well blowouts or pipeline failures, the ERCB initiated a sour gas research project in 1986. After 4 years of scientific study and testing, the ERCB released a 2600-page, 10-volume report in October 1990, advancing the understanding of sour gas behaviour during an accidental release.

The project—monitored by an independent Scientific Advisory Board—consisted of two initiatives; the development of a new computer model, and a Field Measurement Program designed to test the computer model in the field under real conditions. The computer model, known as GASCON2, was developed as a tool for use by industry and the public. The model provides the user with the predicted hydrogen sulphide concentration from a pipeline rupture or well blowout under realistic, worst-case conditions. Additional review of the frequency of blowouts and ruptures showed that the likelihood of the worst-case event happening is extremely remote.

To evaluate and "fine tune" GASCON2, the ERCB conducted extensive field tests. Confidence in the accuracy and ability of the model increased substantially when scientists discovered how closely the model matched actual field observations.

The significance of the completed work is the greater degree of confidence achieved when modelling sour gas releases. The study will enhance the ERCB's ability to make decisions regarding sour gas facilities.

Success of Critical Sour Well Drilling Policy

This past year marked the first year since 1984 that no public hearings were held for the drilling of critical sour wells. Since the inception of the designation "critical sour wells" in 1984, with their special safety requirements, more than 300 such wells have been drilled without a serious well control incident, 70 in 1990 alone.

The ERCB believes that the additional planning, stringent regulatory requirements, vigilant inspections by the ERCB and industry, and direct public involvement, all helped to reduce well control problems.

There has not been a serious well control incident at any of Alberta's 300 critical sour wells drilled since 1984.

Geology Completes Major Computer Systems

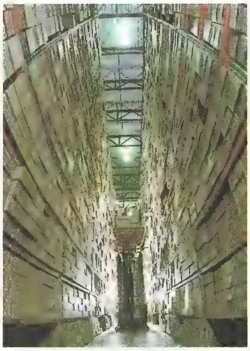
The ERCB's Geology Department is moving rapidly towards computerizing all routine work functions such as database management and administration, reservoir analysis and mapping.

For example, the ERCB reached a milestone with the November 1990 completion of its Integrated Geological Data System (IGDS). The system provides computer storage and retrieval of all geological information collected by the ERCB and reservoir evaluation data generated by Geology Department staff.

The ERCB Geology Department reviews all wells drilled in the province and evaluates any associated reserves. The IGDS has allowed the efficient processing of and access to vast amounts of geological information, innovative data manipulations and enhanced reporting capabilities.

The IGDS program is also crucial to another major computer project: the effort to integrate all in-house mapping systems into one powerful graphic tool. The first of four development phases of this project will be implemented early in 1991. When the entire computer mapping system is complete, its ability to handle any combination of 1200 mappable items on the ERCB's database will provide users with the most up-to-date geological picture available.

Core Research Centre Completes Major Automation Project


The Core Research Centre warehouses 1300 kilometres of core from Alberta wells.

In the ongoing effort to automate the ERCB's internal operations, in April 1990 the ERCB's Core Research Centre (see Techno-focus, page 43), located in Calgary's University Research Park, began operating a fully automated inventory, records management and service and invoicing system.

Instead of the data being recorded on tens of thousands of file cards and processed manually, an operator simply enters a given well location on a computer terminal. In turn, the computer instantaneously checks for the correct storage address of the required material, creates a service request and delivery report, updates the record for that piece of core and automatically records the request for future invoicing.

For the Centre's 5000 annual users, delivery time has been cut by 30 per cent to an average wait of only 10 minutes to receive core material from the 13 000-square-metre warehouse. On the incoming side, the new system has streamlined the entire process of tracking the 30 000 boxes of new core and 300 000 bags of drill cuttings received by the Centre each year.

Another advantage of the system is its tie to the ERCB's mainframe database in downtown Calgary. During the course of reviewing industry submissions and applications, staff geologists can now look up any information on the Centre's database without leaving the office.

Techno-focus #4

World-class Core Research Centre

The ERCB operates the world's largest Core Research Centre, located in Calgary's University Research Park. The Centre stores about 1300 kilometres of core from Alberta's oil and gas wells, and about 10 million vials of drill cuttings representing 82 000 wells.

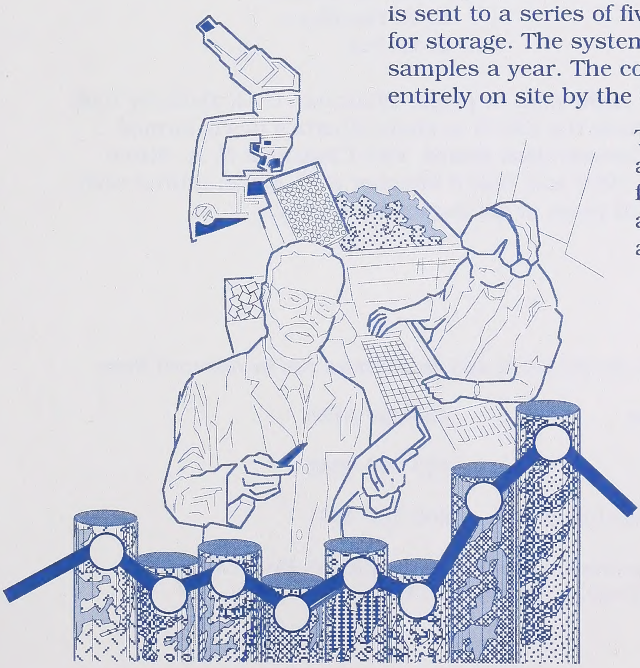
For geologists exploring for oil, gas, oil sands or coal, this research facility is crucial in the quest for new discoveries. Increasingly, it is also becoming important for international and academic researchers, as new technologies are developed to better understand subsurface geology.

Recent advances in medical technology have found their way into geological research. Among the most recent is tomography, normally associated with producing cross-sectional views of human tissues. This X-ray technology is now being used by researchers to gain a three-dimensional image of the inside of core samples. Most of these newer techniques are non-destructive. That is significant because the bulk of existing technology requires using up drill cuttings or core samples.

The Centre has a staff of 32, most of whom are involved in handling, sorting and storing materials. The facility has developed some of its own specialized equipment. The 60 core tables, for example, are height adjustable, so a geologist can raise or lower the cores to a convenient level for viewing. In addition, there are 50 cubicles for viewing drill cuttings. There are close to 10 million vials of cuttings at the Centre, the earliest dating from 1911.

Cuttings arrive unwashed, in small, tagged sample bags. The material is sent to a series of five washing stations before being placed in vials for storage. The system has the capacity to clean and process 350 000 samples a year. The complex sample-washing system was designed entirely on site by the Centre's staff.

The Core Research Centre is financed approximately one-third by user fees, one-third from a portion of the ERCB's drilling licence fee and one-third from the government in the form of an annual grant.



ERCB Management Team

Board Members

F. J. Mink	Co-Chairman
J. P. Prince	Co-Chairman
B. F. Bietz	
R. G. Evans	

Executive Manager—Operations

Vacant

Managers

Accounting	R. T. Bording
Administrative Services	K. G. Sharp
Coal	R. G. Paterson
Communications	J. K. Bales
Data Processing	L. D. Fredlund
Drilling and Production	J. R. Nichol
Economics	J. W. Newton
Employee Relations	R. F. Braun
Environment Protection	H. O. Lillo
Field Operations	W. G. Remmer
Gas	J. D. Dilay
Geology	C. A. Langlo
Hydro and Electric	T. F. Homeniuk
Legal	M. J. Bruni
Oil	N. G. Berndtsson
Oil Sands	R. N. Houlihan
Pipeline	E. G. Fox

As ***Energy Alberta 1990*** went to press, Chairman G. J. DeSorcy took an 18-month leave from the ERCB to chair Alberta's newly formed Natural Resources Conservation Board. Vice Chairman N. A. Strom retired in November 1990 and Board Member E. J. Morin retired early in 1991, both after 35 years of distinguished service.

Additional information on the ERCB and its activities can be obtained from:

1. Information Services	403-297-8190
2. ERCB Library	403-297-8242
3. Communications Department	403-297-4601

All three information sources are located in the ERCB's Head Office at
640 - 5 Avenue S.W., Calgary, Alberta, T2P 3G4.

ERCB

Energy Resources
Conservation Board
640 Fifth Avenue SW
Calgary, Alta. T2P 3G4

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